Chapter 3
Characteristics of Coalbed Methane Production and Associated Hydraulic Fracturing Practices

Understanding the practice of hydraulic fracturing as it pertains to coalbed methane production is an important first step in evaluating its impacts on ground water quality within a USDW. This chapter presents an overview of coalbed methane production in general, as well as a specific analysis of hydraulic fracturing practices. The literature on the size of hydraulic fractures, including the height to which they extend, is described. Fracture height is of interest because it helps understand the potential for impacts to USDWs as the opportunities for fracture connections within a USDW or into a USDW are affected by the height to which a fracture travels.

A preliminary discussion of fracturing fluids is provided, as an introduction to the more detailed description in Chapter 4. Finally, current practices to model and predict hydraulic fracturing mechanics are described.

3.1 Introduction

Coalbed methane is a gas formed as part of the geological process of coal generation, and is contained within all coal, to a greater or lesser concentration. Coalbed methane is exceptionally pure compared to conventional natural gas, in that it contains very small proportions of "wet" compounds (heavier hydrocarbons such as ethane, butane, etc.) and other gases (hydrogen sulfide, carbon dioxide, etc.). Coalbed gas is over 90 percent methane, and suitable for introduction to a commercial pipeline with little or no pre-treatment (Rice, 1993; Levine, 1993).

From the earliest days of coal mining, the flammable gas contained within coal beds has been one of mining's paramount safety problems. Over the centuries, miners have developed several methods to extract the coalbed methane from the coal face and from mine workings.

The production of coalbed methane using wells began in 1971 and was originally intended as a safety measure in conventional coal mines to reduce the explosion hazard posed by methane (Elder and Deul, 1974). In 1980, however, the U.S. Congress enacted a tax credit for "Non-conventional energy production." In 1984, there were fewer than 100 coalbed methane wells in the United States, and most were utilized for mine de-methanization. By 1990, however, the anticipated expiration of the tax credit contributed to the drilling of almost 8,000 coalbed wells nationwide (Pashin and Hinkle, 1997). The Department of Energy and the Gas Research Institute supported extensive research into coalbed exploration and production methods. Federal tax credits (until December 31, 1992) and State Severance Tax exemptions served to subsidize the development of coalbed methane resources (Soot, 1991; Pashin and Hinkle, 1997). The Federal tax credits and incentives expired at the end of 1992, but coalbed methane exploration, development, and reserves (Figure 3-1) have remained stable or increased (Stevens, 1996). At the end of 2000, coalbed methane production from 13 states totaled 1.379 trillion cubic feet, an increase of 156% from 1992. At year-end 2000, coalbed methane production accounted for about 7% of the total U.S. dry gas production and 9% of proven dry gas reserves (EIA, 2001).

Coal is defined as a rock that contains at least 50 percent organic matter. The precursor of coal is peat; plant matter deposited over time in fresh-water swamps associated with coastal deltaic rivers. The geologic origin of most coalbed methane resources throughout the country is very similar. Coalbed methane resources of the United States are usually contained within formations that are between 50 and 350 million years old. This period of time was an era of moderate climate and inland oceans, during which sea levels rose and fell in conjunction with tectonic forces and cycles of increase and decrease in the polar ice masses. As a result, coastal deltas and peat swamps were experienced cycles of inundation and emergence. Throughout 150 million years of geologic time, the shoreline migrated inshore and offshore as sea levels rose and fell, and what was a peat swamp at one time would later be found in 100 feet of water. The amount and type of sedimentation at a given point varied with depth of inundation, from semi-emergent peat swamp (or beach) to lagoon or estuary (Figure 3-2).

The sedimentation patterns in these delta environments determined the presence, thickness, and geometry of present-day coal beds. Each prehistoric coastline was characterized by cycles of sea level rising and lowering. Each of these geologic "coal cycles" features mudstone at the base of the cycle (deeper water) and coal beds at the top (emergence). The number of “coal cycles” determines the number of resulting coal beds. For example, the Black Warrior basin of Alabama features up to 10 cycles, whereas the San Juan basin (New Mexico and Colorado) features as few as three. The short, rising and falling sea level cycles in ancient Alabama produced many thin coal beds, ranging from less than 1 inch in thickness to as much as 4 feet (Carrol et al., 1993; Pashin, 1994 and 1994a), whereas the stable, inland, long-term cycles of the San Juan basin produced single coal beds up to 70 feet thick (Kaiser and Ayers, 1994).

Peat is transformed to coal when it is buried by accumulating sediment and heated in the subsurface over geologic time. The rank of coal describes the amount of energy (Btu) contained in a coal, and is a function of the proportion and type of organic matter (plant or woody), the length and temperature of burial, and the influences of subsequent hydrogeologic and tectonic processes (Carrol et al., 1993; Levine, 1993; Rice, 1993). Methane is generated as part of the process whereby peat is changed to coal. Peat and coals of very low rank do not have sufficient organic matter or burial conditions to generate much methane, and the methane that is generated is usually contaminated by other gases related to decomposition (carbon dioxide, hydrogen sulfide, etc.). Conversely, coals of high rank (anthracite, etc.) have been subjected to geologic temperatures sufficient to drive off most of the methane. Commercial coalbed methane production takes place only in coals of mid-rank, usually Low- to High-Volatile Bituminous coals (Levine, 1993; Rice, 1993).

Coalbeds are characterized by a network of joints and fractures and by a smaller sub-network of small joints called cleats. Joints are larger, systematic, vertical fractures within the coal, spaced 5 to 40 feet apart. Cleats are spaced from 0.1 to 1 inch apart; planar, systematic joints are called face cleats, and the intersecting cross-joints are called butt cleats (Close, 1993; Levine, 1993) (Figure 3-3). Coal has very little natural permeability; coalbed methane and water flows occur within the network of fractures, joints, and cleats.

Methane within coalbeds is not "trapped" under pressure as in conventional gas scenarios. Only about 5 to 9 percent of the methane is present as "free" gas within the joints and cleats. Almost all coalbed methane is *adsorbed* within the micro-porous matrix of the coal (Koenig, 1989; Winston, 1990; Close, 1993). When production begins, water is produced from the joints and cleats in the coal until the pressure declines to the point when methane begins to de-sorb from the coal matrix itself (Gray, 1987). Contrary to conventional gas production, the percentage of water produced *declines* with increasing coalbed methane production, and coalbed methane is produced into the well bore at close to atmospheric pressure (Figure 3-4) (Ely et al., 1990; Schraufnagel, 1993).

The effective natural permeability of coal is very low, typically ranging from 0.1 to 30 millidarcies (McKee et al., 1989). Therefore, almost every coalbed methane production well must be fracture-stimulated to connect the well bore to the joint/cleat system, in order to depressurize the coal matrix and allow coalbed methane to be desorbed and flow to the well (Holditch et al., 1988). Many wells in the San Juan basin are stimulated by creation of a cavity in the open-hole section (using pressure-cycling), but almost every other coalbed methane well is stimulated using hydraulic fracturing. Most wells are stimulated more than once:

- In wells with multiple coal seams present, the hydraulic fracturing process may involve several or multiple stimulations, using from 2 to 5 hydraulic fracture treatments per well (depending on number of seams and spacing between seams);
- Many coalbed methane wells are re-fractured at some time after the initial treatment, in an effort to re-connect the wellbore to the production zones in order to overcome plugging or other well problems (remedial fracture-stimulation) (Holditch, 1990; Saulsberry et al., 1990; Palmer et al., 1991and 1991a; Holditch, 1993).

3.2 Hydraulic Fracturing

A graphical representation of a typical hydraulic fracturing event in a coalbed methane well has been provided to help in the visualization of the fracturing process (Figure 3-5).

This diagram shows the fracture creation and propagation, as well as the proppant placement and fracturing fluid recovery stages.

The Department of Energy prepared a description of hydraulic fracturing basics in collaboration with EPA to inform this study. The complete paper titled "Hydraulic Fracturing" is provided as Appendix A. The following text is from that paper.

Introduction

The first hydraulic fracturing treatment was pumped in 1947 on a gas well operated by Pan American Petroleum Corporation in the Hugoton field (Gidley et al., 1989). The Kelpper Well No. 1, located in Grant County, Kansas was a low productivity well, even though it had been acidized. The well was chosen for the first hydraulic fracture stimulation treatment so that hydraulic fracturing could be compared directly to acidizing. Since that first treatment in 1947, hydraulic fracturing has become a standard treatment for stimulating the productivity of oil and gas wells.

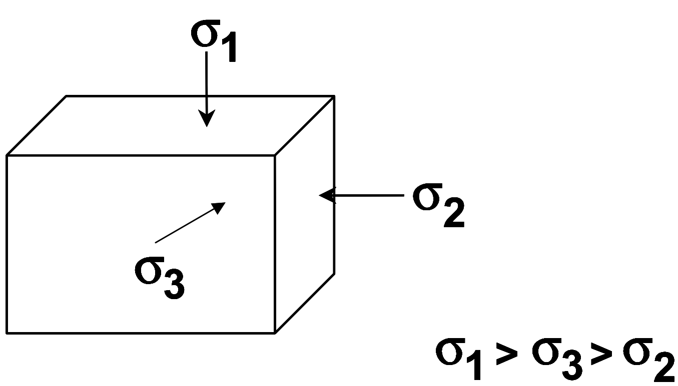
Hydraulic fracturing is the process of pumping a fluid into a wellbore at an injection rate that is too high for the formation to accept in a radial flow pattern. As the resistance to flow in the formation increases, the pressure in the wellbore increases to a value that exceeds the breakdown pressure of the formation that is open to the wellbore. Once the formation "breaks-down", a crack or fracture is formed, and the injected fluid begins moving down the fracture. In most formations, a single, vertical fracture is created that propagates in two directions from the wellbore. These fracture "wings" are 180^o apart, and are normally assumed to be identical in shape and size at any point in time. In naturally fractured or cleated formations, such as gas shales or coal seams, it is possible that multiple fractures can be created and propagated during a hydraulic fracture treatment. Fluid that does not contain any propping agent, often called "pad", is injected to create a fracture that grows up, out and down, and creates a fracture that is wide enough to accept a propping agent. The purpose of the propping agent is to "prop open" the fracture once the pumping operation ceases, the pressure in the fracture decreases, and the fracture closes. In deep reservoirs, we use man-made ceramic beads to prop open the fracture. In shallow reservoirs, sand is normally used as the propping agent.

In general, hydraulic fracture treatments are used to increase the productivity index of a producing well, or the injectivity index of an injection well. The productivity index defines the volumes of oil or gas that can be produced at a given pressure differential between the reservoir and the well bore. The injectivity index refers to how much fluid can be injected into an injection well at a given pressure differential.

In many cases, especially for low permeability formations, damaged reservoirs and horizontal wells in a layered reservoir, the well would be "uneconomic" unless a successful hydraulic fracture treatment is designed and pumped.

In-situ Stresses

Underground formations are confined and under stress. The graphic below illustrates the local stress state at depth for an element of formation. The stresses can be divided into 3 principal stresses. σ_1 is the vertical stress, σ_2 is the maximum horizontal stress, while σ_3 is the minimum horizontal stress, where $\sigma_1>\sigma_2>\sigma_3$. This is a typical configuration for coalbed methane reservoirs. However, depending on geologic conditions, the vertical stress could also be the intermediate (σ_2) or minimum stress (σ_3), as in the graphic below. These stresses are normally compressive and vary in magnitude throughout the reservoir, particularly in the vertical direction (from layer to layer). The magnitude and direction of the principal stresses are important because they control the pressure required to create and propagate a fracture, the shape and vertical extent of the fracture, the direction of the fracture, and the stresses trying to crush and/or embed the propping agent during production.



Local in-situ stress at depth.

A hydraulic fracture will propagate perpendicular to the least principle stress. In some shallow formations the least principal stress is the overburden stress; thus, the hydraulic fracture will be horizontal. Nielsen and Hansen (1987) published a paper where horizontal fractures in coal seam reservoirs were documented. In reservoirs deeper than 1000 ft or so, the least principal stress will likely be horizontal; thus, the hydraulic fracture will be vertical. The azimuth orientation of the vertical fracture will depend upon the azimuth of the minimum and maximum horizontal stresses.

The geometry of hydraulic fractures usually differs between those observed in conventional oil and gas scenarios and those in coalbed methane zones. In conventional hydrocarbon zones, the gas and/or oil are physically "trapped" by the presence of an impermeable confining layer, usually shale. Shale formations present a barrier to upward fracture growth because of their higher "elasticity" and stress contrast (Naceur and

Touboul, 1990). Therefore, for conventional fracturing, the vertical growth of fractures out of the target zone is usually limited by the presence (i.e., stress contrast) of overlying shales. In conventional gas-well fracture environments, fracture half-length (200-1600 feet from the well bore) almost always exceeds fracture height (10-200 feet above the perforations).

In many coalbed methane basins, however, the lithologic properties and stress fields of the coal cycles typically produce fractures that are higher than they are long ('length' refers to horizontal distance from the well bore) (Morales et al., 1990; Zuber, 1990; Holditch et al., 1989; Palmer and Sparks, 1990; Jones and Schraufnagel, 1991; Steidl, 1991; Wright, 1992; Palmer et al., 1991a and 1993).

If the confining 'shale barriers' typical in conventional gas reservoirs do not exist in coalbed methane basins (as is the case in the Black Warrior basin of Alabama, for example), then hydraulic fractures created in coalbed methane deposits are able to grow higher than fractures in 'conventional' gas reservoirs. Because there are no significant barriers to fracture height (Simonson et al., 1978; Ely et al., 1990; Palmer et al., 1991), vertical fractures in the Black Warrior basin typically penetrate several thin coal beds and hundreds of feet of intervening rocks (Teufel and Clark, 1981; Hanson et al., 1987; Holditch et al., 1989; Ely et al., 1990; Palmer et al., 1991b; Schraufnagel et al., 1991; Spafford, 1991; Palmer et al., 1993a) (Figure 3-6).

The economics of coalbed methane production in some basins require tall fractures that penetrate several coal seams. In most coalbed methane basins except the San Juan, coal seams are typically thin (1 to 24 inches) and economically viable production requires the drainage of as many seams as possible. Because coal seams may be vertically separated, operators usually design fracture treatments to enhance the vertical dimension and might perform several fracture treatments within a single well (Ely, et al., 1990; Holditch, 1990; Saulsberry et al., 1990; Spafford, 1991; Holditch, 1993)

Vertical fracture heights in Alabama basins have been measured in excess of 500 feet (Ely et al., 1990; Zuber et al., 1991), and fracture heights of 300 feet are considered typical (Holditch et al., 1989; Lambert et al., 1989; Ely et al., 1990; Saulsberry et al., 1990; Palmer and Sparks, 1990; Spafford, 1991; Palmer et al., 1991 and 1993; Spafford et al., 1993; Gas Research Institute, 1995). Holditch (1993) found similar fracture behavior in wells of the Raton basin. Fracture lengths, however, are typically modeled or measured as less than 200 feet from the well bore (Wright, 1992; Holditch et al., 1989; Lambert et al., 1989; Ely et al., 1990; Saulsberry et al., 1990; Palmer and Sparks, 1990; Spafford, 1991; Palmer et al., 1991 and 1993; Spafford et al., 1993; Gas Research Institute, 1995).

Several researchers conclude (based on pressure behavior during fracturing and several examples where mines penetrated hydraulic fractures) that shallow fractures have a "horizontal component."

- Fractures that are created at shallow depth typically have more of a horizontal than a vertical component. The vertical component is most likely due to the presence of vertical natural fractures (cleats and joints) as pre-existing planes of weakness from which vertical fractures can initiate. The horizontal component probably results from the overburden stress being the minimum stress, as well as increased likelihood of slippages at lithology or boundary interfaces (David Hill, GTI, Personal Communication, 2001).

- Vertical fractures created deeper can propagate vertically to shallower depth and develop a horizontal component. In these "T-fractures", the fracture tip may fill with coal fines and/or intercept a zone of stress contrast, which causes the fracture to "turn" and develop horizontally at a coalbed-mudstone interface. The height of "T-Fractures" can be 200-300 feet above the perforations (Jones et al., 1987; Morales et al., 1990).

Penetration of layers above the coal was observed in nearly half of the fractures intercepted by mines underground (Diamond, 1987), but, as coals become shallower, the potential for significant fracture height growth decreases. In general, horizontal fractures are most likely to exist at shallow depths (less than 1,000 feet). As depth increases, it is more likely that a simple vertical fracture will occur (GRI, 1995).

3.3 Fracturing Fluids

The fluids used for fracture extension are pumped at high pressure into the well, and may be "clear" (most commonly water, but may include acid, oil, or water with friction-reducer additives) or "gelled" (viscosity-modified water, using guar or other gelling agents). As discussed below, the volume of fluids used in a fracturing event can range between 50,000 to 350,000 gallons.

Fracturing fluids are not typically fully recovered through flowback (Halliburton Inc., personal communication, 2002; Willberg et al., 1999; Willberg et al., 1997; Samuel et al., 1997; Palmer, 1991). Fracturing fluids can become entrapped in a formation by three different mechanisms.

1. Fluids can leak off away from the created fracture through smaller secondary fractures. High injection pressures can force the fluids to be transported deep into the secondary fractures, to the point where flow-back efforts may not recover them (Halliburton Inc., personal communication, 2002). The pressure reduction caused by pumping during subsequent production is not always sufficient to recapture all the fluids that have leaked off into the formation.

2. Fluids can become entrapped if a created fracture becomes closed off at some distance away from the well before the proppant has been emplaced.

Differential closing of fractures is not uncommon, according to Halliburton, Inc. (personal communication, 2002). A long fracture can be pinched off at some distance away from the well. This reduces the effective fracture length that gas can travel through to the production well. Fluids trapped beyond the "pinch point" cannot be recovered during flowback (Halliburton Inc., personal communication, 2002).

3. Fluids can become adsorbed to the formation surface or react with the formation chemically. These physical and chemical interactions can prevent the fluid from being recovered (Halliburton Inc., personal communication, 2002).

The actual amount of fluid that is stranded in the process depends strongly upon the efficiency of the fracturing fluid and the rate of closure, which is based on formation characteristics and the depth of the targeted formation. In shallow wells, the closure time will be slow because the forces required to produce closure are usually not high. Depending on the time required to begin production after fracturing, this may minimize the amount of fluids that get stranded. If the stimulation fluids do not flow back to the wellbore where they were injected, presumably due to the formation material having low permeability, then the fluids will not likely migrate much greater distances to a water well. The fluid dynamics in the area should also limit movement of stranded fluids away from the production well since during production the lowest pressure is typically in the coalbed methane well.

In most cases, when the fracturing pressure is released, the fracture closes in response to compressive stresses acting in the subsurface. Because the primary purpose of fracturing is to increase the effective permeability of the well, a closed fracture is of little use. Conversely, if the operator could "prop" the fracture open, the enhancement of permeability due to the fracture would remain permanent. To this end, operators utilize a system of "proppants" and fluids to create and preserve a high-permeability fracture-channel into the formation. The most common "proppant" used in coalbed methane wells is sand. During hydraulic fracture creation, up to 300,000 pounds of coarse sand is pumped into the fracture by means of a "carrier" fluid of high viscosity. Most operators use guar gum or polymers to enhance viscosity (and sand-carrying ability) by "gelling" the fracturing fluid, but water can also be used at reduced proppant carrying efficiency. In a perfect environment, fracturing fluids and sand-laden gels are pumped to the extreme ends of the fracture, and a complete, permeable pathway is created from the formation into the well.

Each pore tends to "leak off" some of the fracturing fluid to neighboring pores, off-axis; these fluids are lost to the process (Figure 3-7). Depending on the permeability of the rocks and the surface area of the fracture, a sizeable volume of fracturing fluids may be lost to other pores, and the fracturing or emplacement effect is lessened. Operators try to reduce the tendency for leak-off by using gels, especially a class of gels that are "cross-linked". Cross-linking involves the addition of a variety of chemical species that allow gels to form a "filter cake" and act almost semi-solid when pumping velocity drops, such as when the fluid leaves the main fracture channel and begins to "leak-off" into pores. Gels and cross-link agents serve to seal-off the leaking pores, and focus the hydraulic energy into the main fracture channel, in order to extend the fracture during the initial pumping phase or to emplace proppant during subsequent pumping phases. The best analogy is the use of "Stop-Leak" chemicals to fix a leak in an automobile radiator.

The use of cross-link agents can also create another problem. If the entry pores to the fracture channel remain blocked off, production fluids cannot enter the fracture and the permeability increase is entirely defeated. Therefore, the use of cross-linkers requires that operators also use "breaker" chemicals, which are pumped into the fracture to break down the cross-links chemically, and allow the gel to be pumped back down the fracture and out of the well.

A typical coalbed fracture treatment utilizes from 50,000 to 350,000 gallons of various stimulation and fracturing fluids, and from 75,000 to 320,000 pounds of sand as proppant (Holditch et al., 1988 and 1989; Jeu et al., 1988; Hinkel et al., 1991; Holditch, 1993; Palmer et al., 1991, 1993, and 1993a). These volumes are less than those typically used in fracture stimulation treatments in conventional coalbed methane reservoirs, where over 500,000 gallons of fracturing fluid and 1,000,000 pounds of proppant are used per well. Depending on the basin and treatment design, the nature of stimulation and fracturing fluids can include plain water, plain water containing gels or solvents, diesel fuel, and hydrochloric acid, with or without the use of proppants.

For fracture treatments of wells in homogeneous formations in conventional gas fields, however, injection is temporary and a large fraction of the stimulation fluid is subsequently pumped back from the well when production resumes. Because of the heterogeneous, stratified, and fractured nature of coal deposits, however, it is likely that some volume of stimulation fluids is stranded in zones that were not completely "propped".

The height of a hydraulic fracture can be expressed in two ways: the height of maximum vertical growth during extension, and the "propped height" (the amount of fracture in which proppant has been distributed). This distinction is important, because during the initial phases of the fracturing process, large volumes of stimulation fluid are pumped at high rate to the tip of the fracture, in order to achieve maximum extension. Subsequent phases pump fluids to emplace proppant into the fracture, but this emplacement is never complete, and the propped height is always less than the height of maximum vertical growth. Because of the stratified and fractured nature of many coalbed deposits, and because hydraulic fractures close unless propped, fracturing fluids might not be recovered from the portion of the fracture that is not propped. In most cases, propped height is only 60 to 75 percent of maximum vertical fracture growth (Mavor et al., 1991; Rahim and Holditch, 1992; Nolte and Smith, 1981; Nolte and Economides, 1991; Zuber et al., 1991), and, in cases where proppant "screens out" or emplacement partially fails, proppant may exist in 20 percent or less of fracture height.

Similarly, natural or propagating fractures may open and allow fluids to flow through during high fracturing pressure, but may also subsequently trap the fluids as they close after fracturing pressure decreases (the "check-valve" effect) (Warpinski et al., 1988; Palmer et al., 1991a). Experiments performed by Stahl and Clark (1991) confirm that this phenomenon dominates fluid-loss behavior in coal beds. Contrary to conventional formations where "leak-off" and fluid invasion may penetrate only a few inches, stimulation fluids in coal penetrate from 50 to 100 feet away from the fracture and into the surrounding formation (Palmer et al., 1991; Puri et al., 1991) (Figures 3-7 and 3-8). In these and other cases, when stimulation ceases and production resumes, these chemicals may not be completely recovered and pumped back to the coalbed methane well, and, if mobile, may be available to migrate through an aquifer.

Palmer and others (1991a) found that only 61 percent of fracturing fluids were recovered during a 19-day production sampling of a coalbed well in the Black Warrior basin, Alabama. Samuel et al. (1997) report that several studies relating to guar-based polymer gels document flow-back recovery rates of approximately 30-45%. The paper did not discuss the duration over which flow-back recovery rates were measured. Willberg et al. (1997) report that polymer recovery rates during flowback averaged 29-41% of the amount pumped into the fracture. The results from this study were derived from tests performed on 10 wells over periods of four or five days (Willberg et al., 1997). Willberg et al. (1998) report that polymer returns at conservative flow back rates averaged 25-37% of the amount pumped into the fracture, while returns at aggressive flow back rates averaged 37-55%. The results from this study were derived from tests performed on 15 wells over periods of two days at aggressive flow back rates and five days at conservative flow back rates.

3.4 Predicting, Monitoring, and Measuring Fracture Height

Several testing and modeling methods are available to operators to predict or assess both maximum extension and "propped" fracture height. Both the current and older methods were investigated with regard to possible use by operators or regulators to predict or diagnose potential fracture problems relative to USDWs. This summary discussion of a highly complex array of technical topics is necessarily brief, and may not reflect the latest developments in 3-D fracture modeling due to the delay between model development and widespread publication. In general, however, these methods fall into two areas: 1) predictive modeling tools; and, 2) diagnostic tests within and outside the well bore.

3.4.1 Modeling

The basic elements of fracture modeling were developed between 1955 and 1961 (Nolte and Economides, 1991). Predictive modeling is used primarily for the design of fracture stimulation treatments (i.e., the necessary volume and pump rate of fluids and proppants that are required to achieve a desired fracture geometry), whereas history-matching tools attempt to refine predictive models using fracturing pressure behavior, production characteristics, and post-fracturing transient testing. The most effective modeling efforts utilize these steps:

1. Analyze all available pre-fracture production and pressure-transient data to estimate permeability, skin factor (i.e. well efficiency), and reservoir pressure.

2. Analyze all available logs to divide the treatment interval into layers by category, based on lithology, fluid content, and porosity. Estimate mechanical properties for all layers using logs.

3. Use this layer description in a hydraulic fracture propagation model to compute maximum and propped fracture geometry and properties.

4. Use estimated values of reservoir permeability and fracture half-length to simulate post-fracture production performance. Match the production computed from the reservoir model with the actual well production data.

5. Compare the estimates of fracture geometry and formation permeability obtained from the pressure-transient analyses, the production-data analyses, and the fracture propagation model. If these estimates do not agree, alter the reservoir layer description and repeat the analyses (Rahim et al., 1998).

Many models rely on simplifying assumptions to simulate flow in geologic formations. These typically include assumptions that the modeled formations are vertically and laterally homogeneous, as well as isotropic. However, actual formations do not approximate these assumptions. Additionally, use of predictive models tends to be somewhat subjective by nature.

First, accurate measurement of the in-situ stress and elasticity characteristics of subject rocks is necessary for accurate modeling, but is expensive and rarely performed. Rather, values are assumed or taken from the published literature. Second, effective modeling requires knowledge of and allowance for the detailed stratigraphy of the beds of the entire coal section. Warpinski et al. (1982) found that even microscopically-thick ash beds can drastically change the geometry and height of a hydraulic fracture. Instead, most tools utilize simplified, 2- or 3-layered geology models in order to reduce computing and data requirements, when, in fact, a 30- or 50-layer model may be necessary to accurately predict fracture height (Rahim et al., 1998).

Third and most important, all predictive models require the assumption of one or more critical parameters of fracture geometry, whether the assumption is made by the operator or is an implicit condition of the model design or programming. Because length and width are the fracture characteristics most important for gas production, most older (and some newer) modeling tools require that the operator estimate combined sentences either height, fracture transmissivity, or fracture geometry-type (Nolte and Economides, 1991). The newest, pseudo-3d (P3D) models, however, simultaneously predict height, width, and length based on treatment input data and reservoir parameters (Jon Olson, U of T, Personal Communication, 2001). In any case, all models require a series of repeat runs using a range of variables, and the operator chooses the result judged most appropriate (Rahim et al., 1998).

In summary, for some predictive models, fracture height is not usually a primary predictive output. For almost all other models, including modern 3-D simulators, the choices and assumptions of input variables provide overall results that are somewhat more subjective rather than absolute.

3.4.2 Fracture Diagnostics

The following technical discussion is taken directly from a Department of Energy paper titled "Hydraulic Fracturing". This paper was provided directly to EPA by the DOE, and contains examples of hydraulic fracturing in both conventional oil and gas scenarios, and also for coalbed methane production. A complete copy of this paper is provided as Appendix A.

Fracture diagnostics involves analyzing the data before, during and after a hydraulic fracture treatment to determine the shape and dimensions of both the created and propped fracture. Fracture diagnostic techniques have been divided into several groups.

Direct far field techniques

Direct far field methods are comprised of tiltmeter fracture mapping and microseismic fracture mapping techniques. These techniques require delicate instrumentation that has to be emplaced in boreholes surrounding and near the well to be fracture treated. When a hydraulic fracture is created, the expansion of the fracture will cause the earth around the fracture to deform. Tiltmeters can be used to measure the deformation and to compute the approximate direction and size of the created fracture. Surface tiltmeters are placed in shallow holes surrounding the well to be fracture treated and are best for determining fracture orientation and approximate size. Downhole tiltmeters are placed in vertical wells at depths near the location of the zone to be fracture treated. As with surface tiltmeters, downhole tiltmeter data can be analyzed to determine the orientation and dimensions of the created fracture, but are most useful for determining fracture *height. Tiltmeters have been used on an experimental basis to map hydraulic fractures in coal seams (Nielson and Hanson, 1987).*

Microseismic fracture mapping relies on using a downhole receiver array of accelerometers or geophones to locate microseisms or micro-earthquakes that are triggered by shear slippage in natural fractures surrounding the hydraulic fracture. In essence, noise is created in a zone surrounding the hydraulic fracture. Using sensitive arrays of instruments, the noise can be monitored, recorded, analyzed and mapped.

Microseismic monitoring has traditionally been too expensive to be used on anything but research wells, but its cost has dropped dramatically in the past few years, so although stll expensive (on the order of $50,000 to $100,000), it is being used more commonly throughout the industry. If the technology is used at the beginning of the development of a field, however, the data and knowledge gained are often used on subsequent wells, effectively spreading out the costs.

Direct near-wellbore techniques

Direct near-wellbore techniques are run in the well that is being fracture treated to locate or image the portion of fracture that is very near (inches) the wellbore. Direct near-wellbore techniques consist of tracer logs, temperature logging, production logging, borehole image logging, downhole video logging, and caliper logging. If a hydraulic fracture intersects the wellbore, these direct near-wellbore techniques can be of some benefit in locating the hydraulic fracture.

However, these near-wellbore are not unique and cannot supply information on the size or shape of the fracture once the fracture is 2-3 wellbore diameters in distance from the wellbore. In coal seams, where multiple fractures are likely to exist, the reliability of these direct near-wellbore techniques are even more speculative. As such, very few of these direct near-wellbore techniques are used on a routine basis to look for a hydraulic fracture.

Indirect fracture techniques

The indirect fracture techniques consist of hydraulic fracture modeling of net pressures, pressure transient test analyses, and production data analyses. Because the fracture treatment data and the post-fracture production data are normally available on every well, the indirect fracture diagnostic techniques are the most widely used methods to determine the shape and dimensions of both the created and the propped hydraulic fracture.

The fracture treatment data can be analyzed with a P3D fracture propagation model to determine the shape and dimensions of the created fracture. The P3D model is used to history match the fracturing data, such as injection rates and injection pressures. Input *data, such as the in-situ stress and permeability in key layers of rock can be varied (within reason) to achieve a history match of the field data.*

Post-fracture production and pressure data can be analyzed using a 3D reservoir simulator to estimate the shape and dimensions of the propped fracture. Values of formation permeability, fracture length and fracture conductivity can be varied in the reservoir model to achieve a history match of the field data.

The main limitation of these indirect techniques is that the solutions are not very unique and require as much fixed data as possible. For example, if the engineer has determined the formation permeability from a well test or production test prior to the fracture treatment, so that the value of formation permeability is known and can be fixed in the models, the solution concerning values of fracture length become more unique. Most of the information in the literature concerning post-fracture analyses of hydraulic fractures has been derived from these indirect fracture diagnostic techniques.

Limitations of fracture diagnostic techniques

Warpinski (1996) discussed many of these same fracture diagnostic techniques. The following Table from Warpinski's paper lists certain diagnostic techniques and their limitations. In general, fracture diagnostics is expensive and only used in research wells. Fracture diagnostic techniques do work and can provide important data when entering a new area or a new formation. However, in coal seam wells, where costs must be minimized to maintain profitability, fracture diagnostic techniques are rarely used and are generally cost prohibitive.

Table 3-1. Limitations of Fracture Diagnostic Techniques

Parameter	Technique	Limitation
Fracture Height	Tracer logs	Shallow depth of investigation; shows height only near the wellbore
Fracture Height	Temperature logs	Difficult to interpret; shallow depth of investigation; shows height only near wellbore
Fracture Height	Stress profiling	Does not measure fracture directly; must be calibrated with *in-situ* stress tests
Fracture Height	P3D models	Does not measure fracture directly; estimates vary depending on which model is used
Fracture Height	Microseismic	Optimally requires nearby offset well; difficult to interpret; expensive
Fracture Height	Tiltmeters	Difficult to interpret; expensive and difficult to conduct in the field
Fracture Length	P3D models	Length inferred, not measured; estimates vary greatly depending on which model is used
Fracture Length	Well testing	Large uncertainties depending upon assumptions and lack of prefracture welltest data
Fracture Length	Microseismic	Optimally requires nearby offset well; difficult to interpret; expensive
Fracture Length	Tiltmeters	Difficult to interpret; expensive and difficult to conduct in the field
Fracture Azimuth	Core techniques	Expensive to cut core and run tests; multiple tests must be run to assure accuracy
Fracture Azimuth	Log techniques	Requires open hole logs to be run; does not work if natural fractures are not present
Fracture Azimuth	Microseismic	Analysis intensive; expensive for determination of azimuth

3.4.3 Consistency of Fracture Behavior

The length, height, width, azimuth, geometry, and other characteristics of hydraulic fractures created by stimulation of subsurface formations are a function of several, interactive factors, primarily:

1. The stratigraphic relationship and the type and thickness of rocks that make up the fracturing section, and the presence of existing, natural fractures;

2. The petro-physical properties of the rocks of the target zone and of the over- and under-lying strata, especially their 'Modulus of Elasticity' (Young's Modulus);

3. The amount and distribution of the tectonic and overburden stresses present in the fracturing section;

4. The "pressure profile" (pumping pressure and rate versus time) and volume and type of fluids used in the hydraulic fracturing process, and the use of proppants (Gidley et al., 1989; Naceur and Touboul, 1990; Mahrer, 1991).

These factors are capable of being estimated, measured, or tested, and the characteristics of the stimulation can be carefully controlled. No two hydraulic fractures, however, exhibit exactly the same behavior or characteristics, even for stimulations performed a few hundred feet apart in the same field. In some cases, differences in fracture behavior and well productivity can be extreme, and identical wells drilled and stimulated on the same day, using the same methods, can vary from prolific producer to dismal, plugged-out failure. These differences in fracture behavior are usually due in part to minute (but influential) flaws and imperfections that exist in the rocks as relics of the processes of sedimentation that created them. Therefore, a valid measurement of rock properties at one location can be invalid at another (Hanson et al., 1987; Jones et al., 1987; Jones et al., 1987a; Palmer et al., 1989; Morales et al., 1990; Naceur and Touboul, 1990; Jones and Schraufnagel, 1991; Palmer et al., 1993a; Elbel, 1994). For example, the localized presence of a shallow clay layer as thin as 10 millimeters at the upper contact of a coal seam (possibly due to the presence of a small depression in the surface during coal emergence), can cause a vertically-propagating, shallow hydraulic fracture to 'turn' horizontal, and fail to penetrate the next overlying coal seam (Jones et al., 1987; Palmer et al., 1989; Morales et al., 1990; Palmer et al., 1991 and 1993a). These small differences within formations account for much of the difference between fracture stimulations, and are the usual cause of production variance among wells in the same project or area.

Similarly, the procedures and fracturing fluids used to stimulate coalbed methane wells differs from operator to operator in a single basin, due to local characteristics of geology and depth, and to perceived advantages of cost, effectiveness, production characteristics, or other factors. For example, some operators in the Black Warrior basin of Alabama utilize elaborate, multi-stage stimulations that feature three to seven different stimulation fluids, including acids, gels of various properties, and 'breaker' and cleanup fluids. Other, nearby operators, however, choose to realize a substantial cost advantage by using only plain water, at the cost of penetrating fewer coal seams and realizing potentially lower gas production (Palmer et al., 1993a).

On a larger scale, fracture stimulations in coalbed methane projects in different basins may share common rock types and characteristics, but fracture behavior usually differs significantly. In addition to the universal existence of rock imperfections that can affect fracture behavior, adjoining basins may be subject to widely varying applications of tectonic stresses. Geologists interpret the magnitude and orientation of tectonic stresses in retrospect by observing its effect on fracture behavior (e.g., Rahim et al., 1998).

3.5 Summary

Coalbed methane development began as a safety measure to extract methane, an explosion hazard, from coal prior to mining. Since 1980, coalbed methane production has grown rapidly, spurred on by tax incentives to develop non-conventional energy production. At the end of 2000, coalbed methane production from 13 states totaled 1.379 trillion cubic feet, an increase of 156% from 1992. At year-end 2000, coalbed methane production accounted for about 7% of the total U.S. dry gas production and 9% of proven dry gas reserves (EIA, 2001).

Methane within coalbeds is not "trapped" under pressure as in conventional gas scenarios. Only about 5 to 9 percent of the methane is present as "free" gas within the joints and cleats. Almost all coalbed methane is *adsorbed* within the micro-porous matrix of the coal (Koenig, 1989; Winston, 1990; Close, 1993). When production begins, water is produced from the joints and cleats in the coal until the pressure declines to the point when methane begins to de-sorb from the coal matrix itself (Gray, 1987). Contrary to conventional gas production, the percentage of water produced *declines* with increasing gas production, and gas is produced into the well bore at close to atmospheric pressure (Ely et al., 1990; Schraufnagel, 1993).

Hydraulic fracturing is commonly used to improve the connection between the production well and the coal formation to facilitate methane production. In wells with multiple coal seams present, the hydraulic fracturing process may involve several or multiple stimulations, using from 2 to 5 hydraulic fracture treatments per well (depending on number of seams and spacing between seams). In addition, many coalbed methane wells are re-fractured at some time after the initial treatment, in an effort to re-connect the wellbore to the production zones to overcome plugging or other well (Holditch, 1990; Saulsberry et al., 1990; Palmer et al., 1991and 1991a; Holditch, 1993).

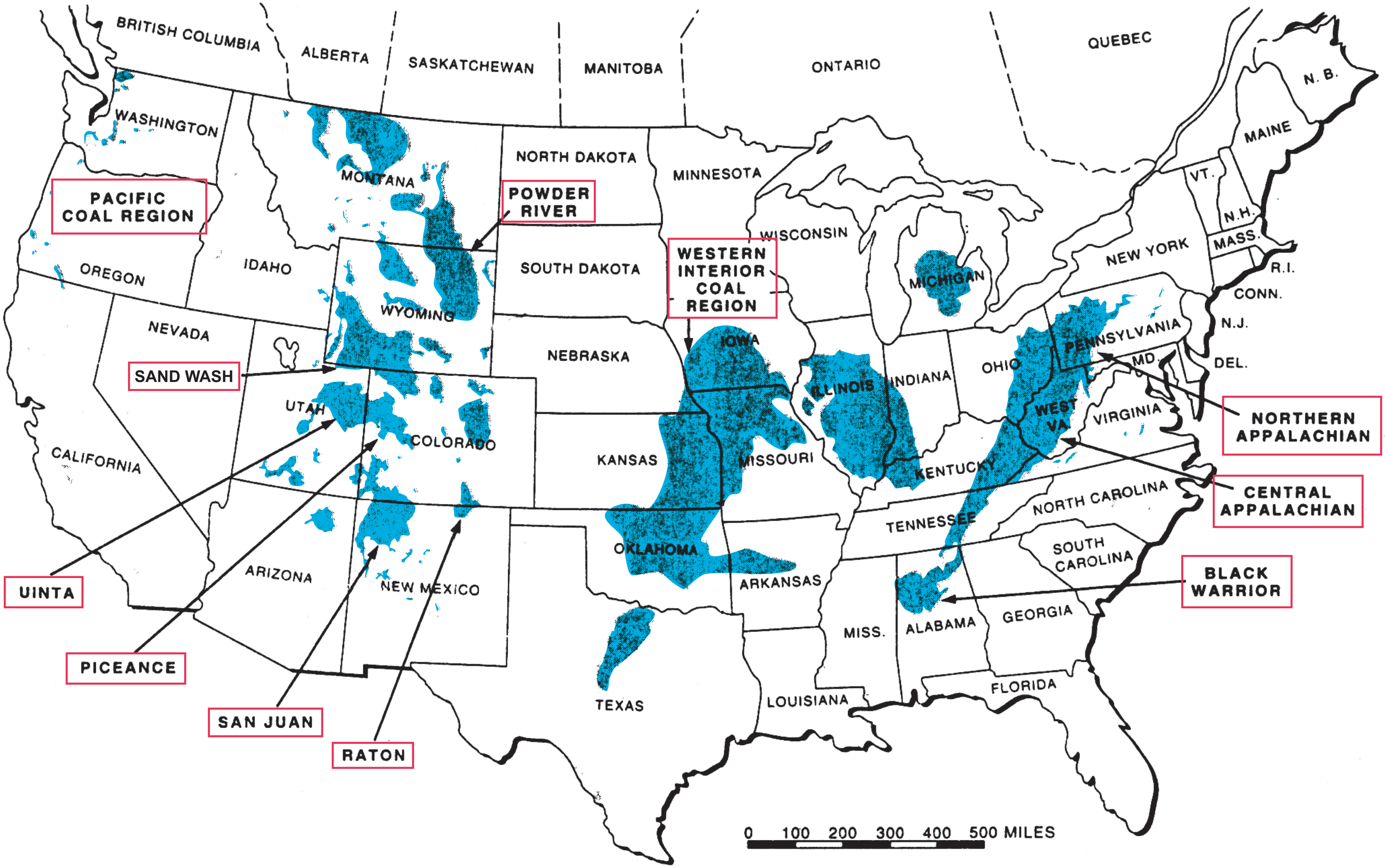
In most coalbed methane basins, the lithologic properties and stress fields of the coal cycles can produce fractures that are higher than they are long ('length' refers to horizontal distance from the well bore) (Morales et al., 1990; Zuber, 1990; Holditch et al., 1989; Palmer and Sparks, 1990; Jones and Schraufnagel, 1991; Steidl, 1991; Wright, 1992; Palmer et al., 1991a and 1993). Vertical fracture heights in Alabama basins have been measured in excess of 500 feet (Ely et al., 1990; Zuber et al., 1991).

Vertical fractures created deeper can propagate vertically to shallower depth and develop a horizontal component. In these "T-fractures", the fracture tip may fill with coal fines and/or intercept a zone of stress contrast, which causes the fracture to "turn" and develop horizontally at a coalbed-mudstone interface. The height of "T-Fractures" can be 200-300 feet above the perforations (Jones et al., 1987; Morales et al., 1990).

The fluids used for fracture extension are pumped at high pressure into the well, and may be "clear" (most commonly water, but may include acid, oil, or water with friction-reducer additives) or "gelled" (viscosity-modified water, using guar or other gelling agents). Hydraulic fracturing in coalbed methane wells may require treatment sizes ranging from 50,000 to 350,000 gallons of fracturing fluids, and from 75,000 to 320,000 pounds of sand as proppant, which maintains the fracture opening after the pumping pressure is released. (Holditch et al., 1988 and 1989; Jeu et al., 1988; Hinkel et al., 1991; Holditch, 1993; Palmer et al., 1991, 1993, and 1993a).

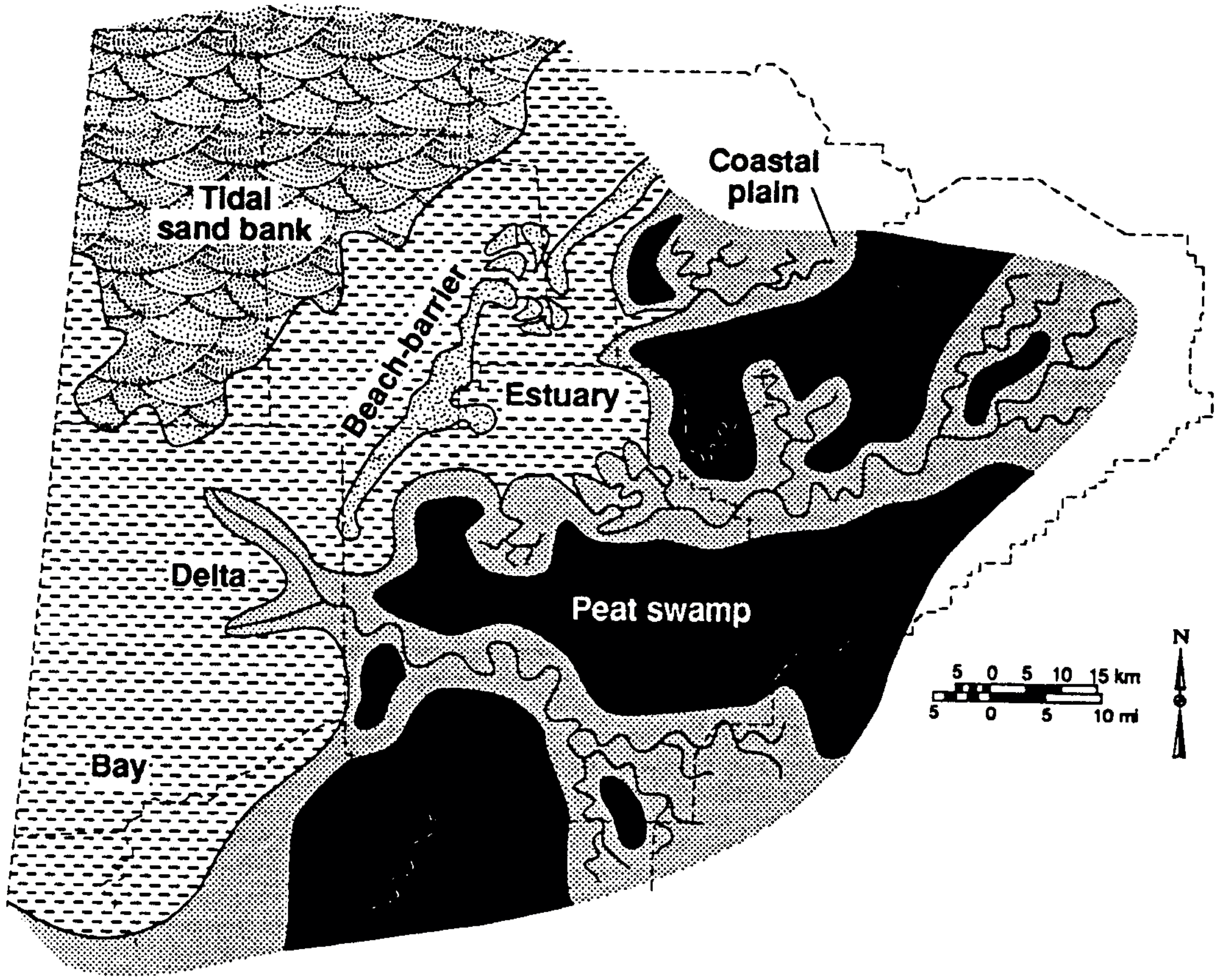
In any fracturing job, fracturing fluids are lost to the formation. Palmer (1991) observed that for fracture stimulations in multi-layered formations, 60 percent of stimulation fluids were recovered during a 19-day production sampling of a coalbed well in the Black Warrior basin. Samuel et al. (1997) report that several studies relating to guar-based polymer gels document flow-back recovery rates of approximately 30-45%. Willberg et al. (1997) report that polymer recovery rates during flowback averaged 29-41% of the amount pumped into the fracture. Willberg et al. (1998) report that polymer returns at conservative flowback rates averaged 25-37% of the amount pumped into the fracture, while returns at aggressive flowback rates averaged 37-55%.

Predictive fracture modeling is used primarily for the design of fracture stimulation treatments (i.e., the necessary volume and pump rate of fluids and proppants that are required to achieve a desired fracture geometry), whereas history-matching tools attempt to refine predictive models using fracturing pressure behavior, production characteristics, and post-fracturing transient testing. For some predictive models, fracture height is not usually a primary predictive output. For almost all other models, including modern 3-D simulators, the choices and assumptions of input variables provide overall results that are somewhat more subjective rather than absolute. Fracture diagnostics involves analyzing the data before, during and after a hydraulic fracture treatment to determine the shape and dimensions of both the created and propped fracture. These diagnostics can be divided into direct far field techniques, direct near-wellbore techniques, and indirect fracture techniques. In general, fracture diagnostic techniques are expensive and are only used in research wells. Fracture diagnostic techniques do work and can provide important data when entering a new area or a new formation. However, in coal seam wells, where costs must be minimized to maintain profitability, fracture diagnostic techniques are rarely used and are generally cost prohibitive. Ultimately, small differences within formations (which are difficult to include during a modeling simulation) account for much of the difference between fracture stimulations, and are the usual cause of production variance and fracture growth differences among wells in the same project or area.



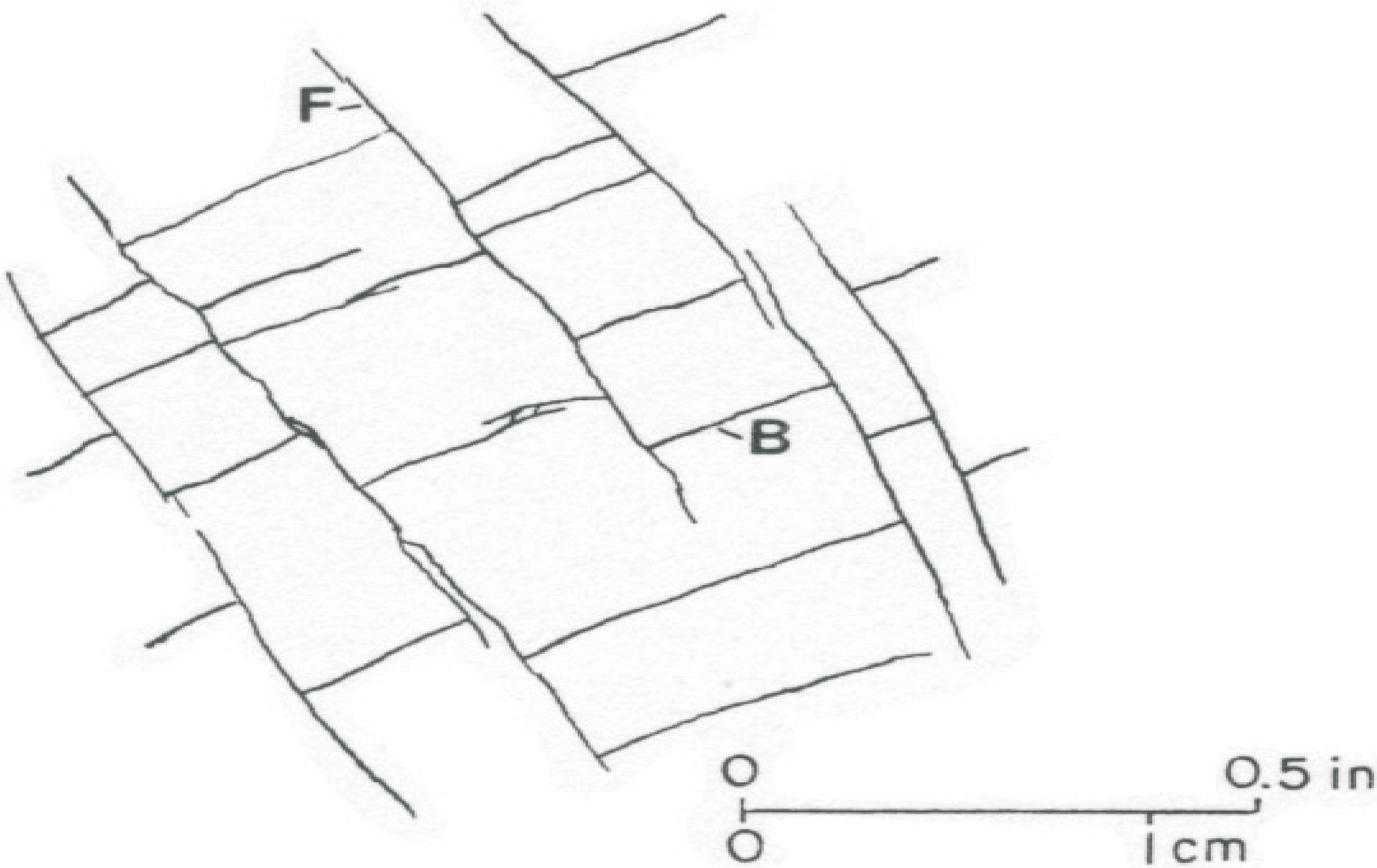
Locus Map of Major U.S. Coal Basins
(Quarterly Review, Methane From Coal Seams Technology, 1993)

1027/reports/ch3/fig-3-1.eps	Figure 3-1



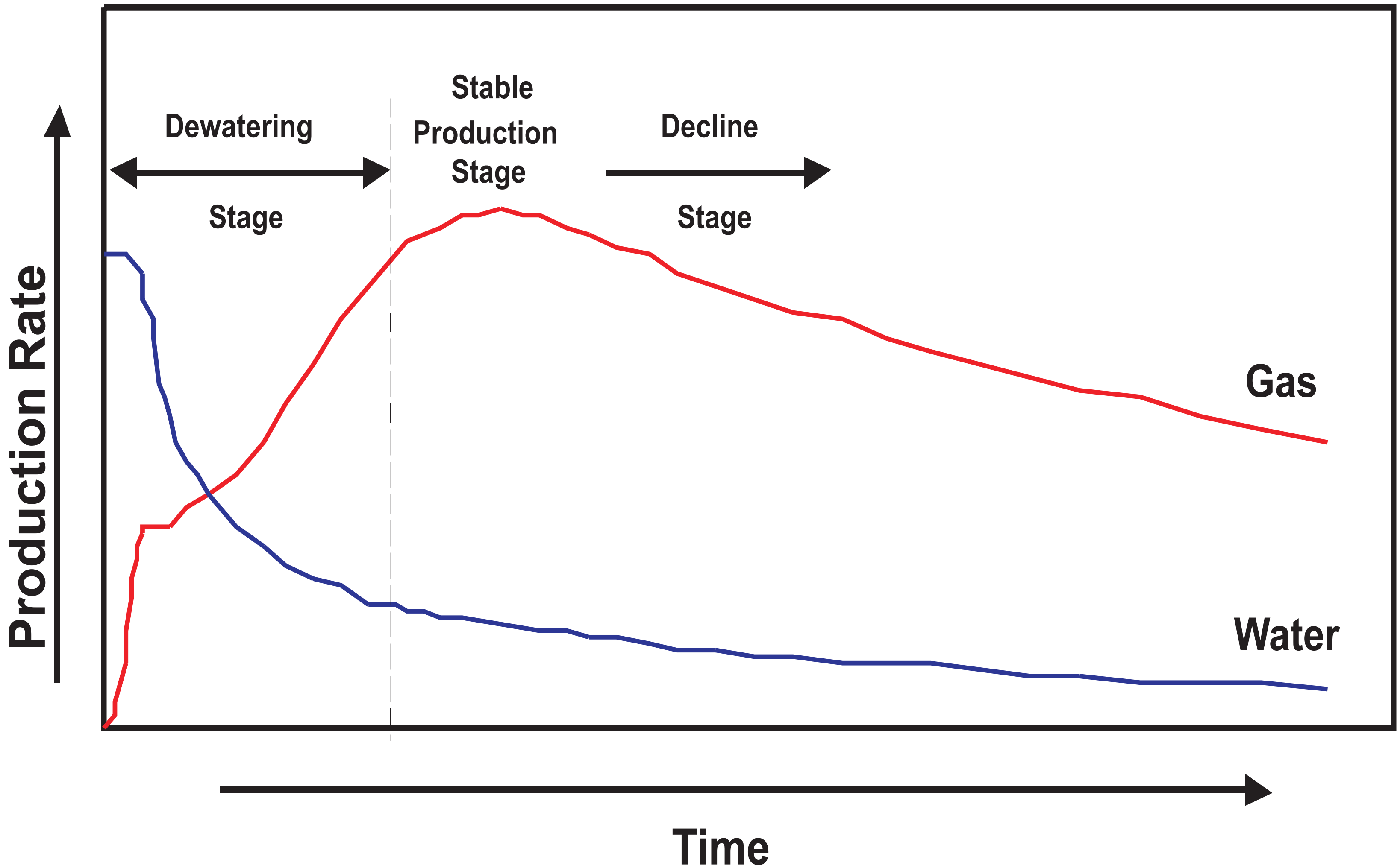
Geography of an Ancient Peat-Forming System (example from Black Warrior Basin, Alabama)
(Pashin and Hinkle, 1997)

9/17/01 kk 1027-3-02.cdr	Figure 3-2



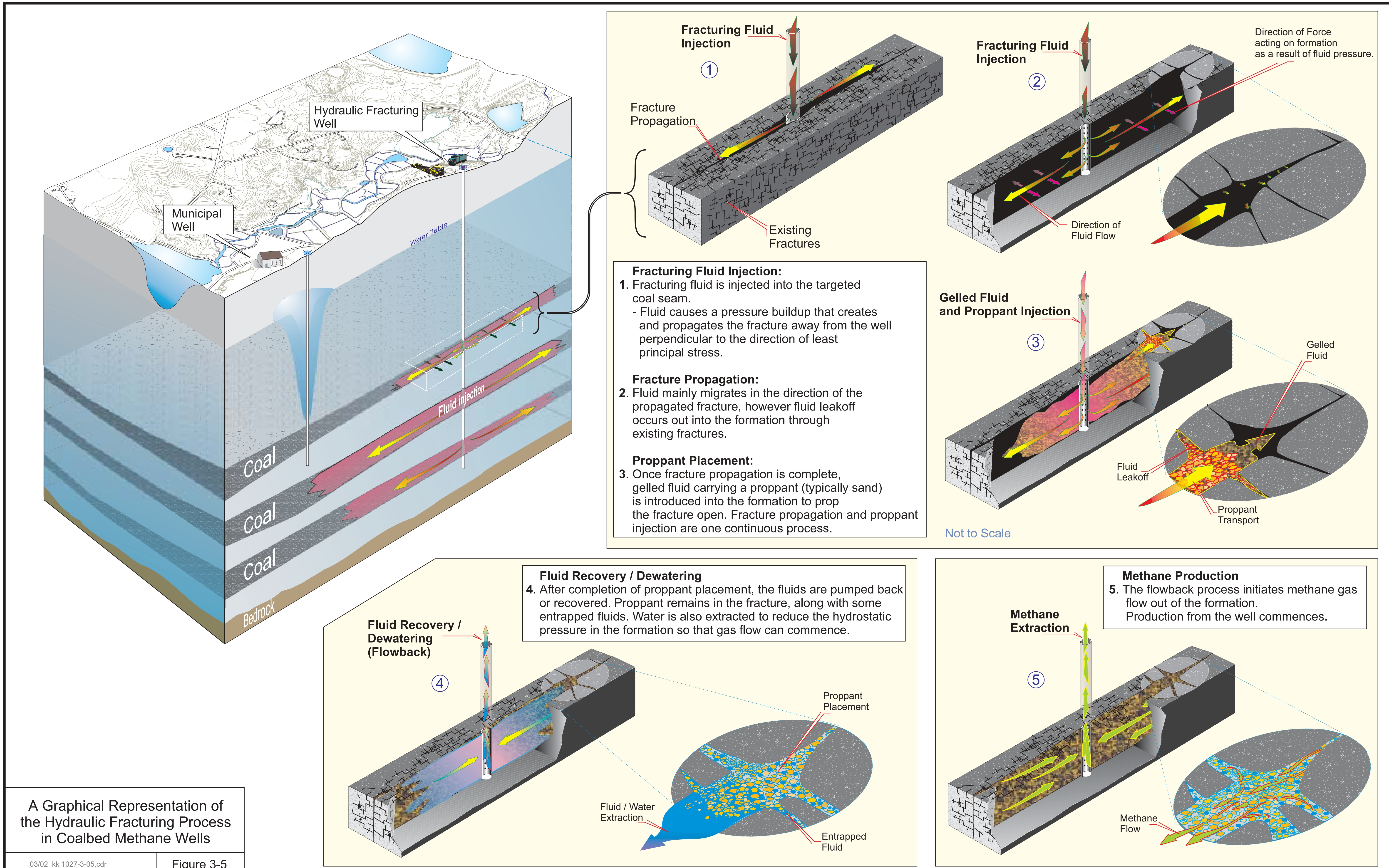
Schematic Representation of “Face Cleat” (F) and “Butt Cleat” (B) (Ayers et al., 1994)

9/17/01 kk 1027-3-03.cdr	Figure 3-3



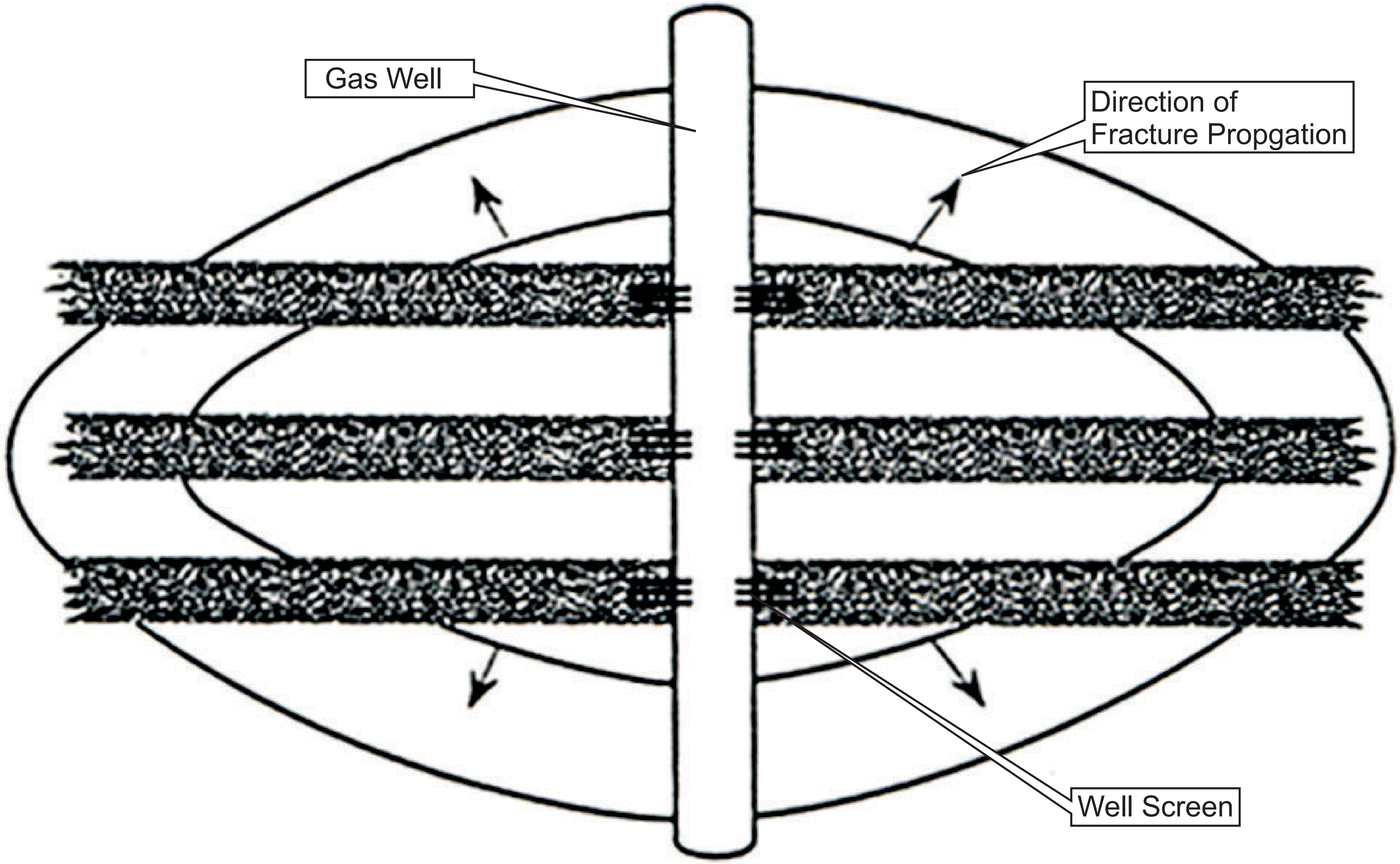
Water and Gas Production Over Time (Saulsberry et al., 1996)

7/14/01 kk 1027-HF-3-04.cdr	Figure 3-4



A Graphical Representation of the Hydraulic Fracturing Process in Coalbed Methane Wells

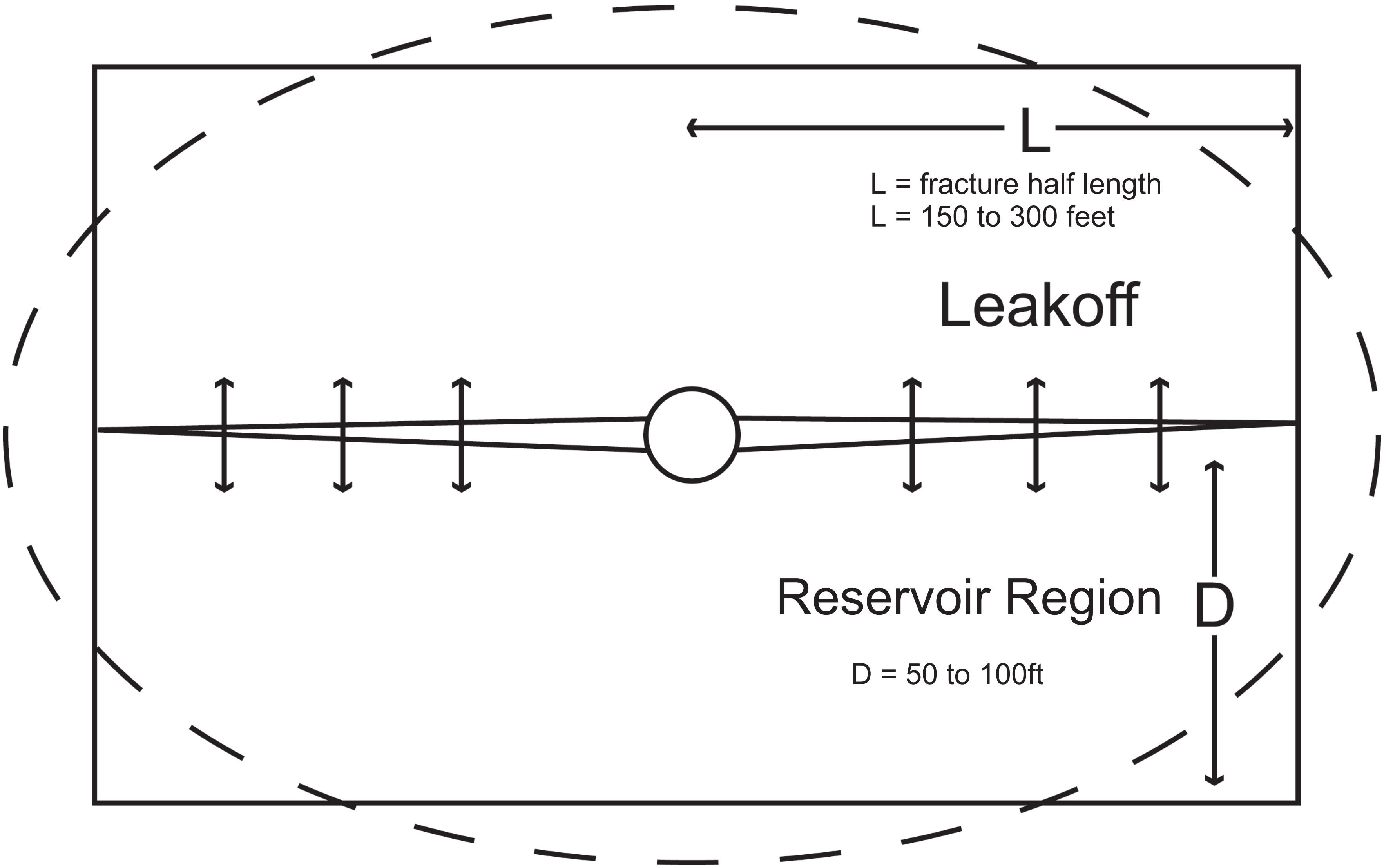
Figure 3-5



Side-View of a Vertical Hydraulic Fracture Typical of Coalbeds
Most hydraulic fractures penetrate several coal seams.
(Palmer et al., 1991)

7/14/01 kk 1027-HF-3-06.cdr

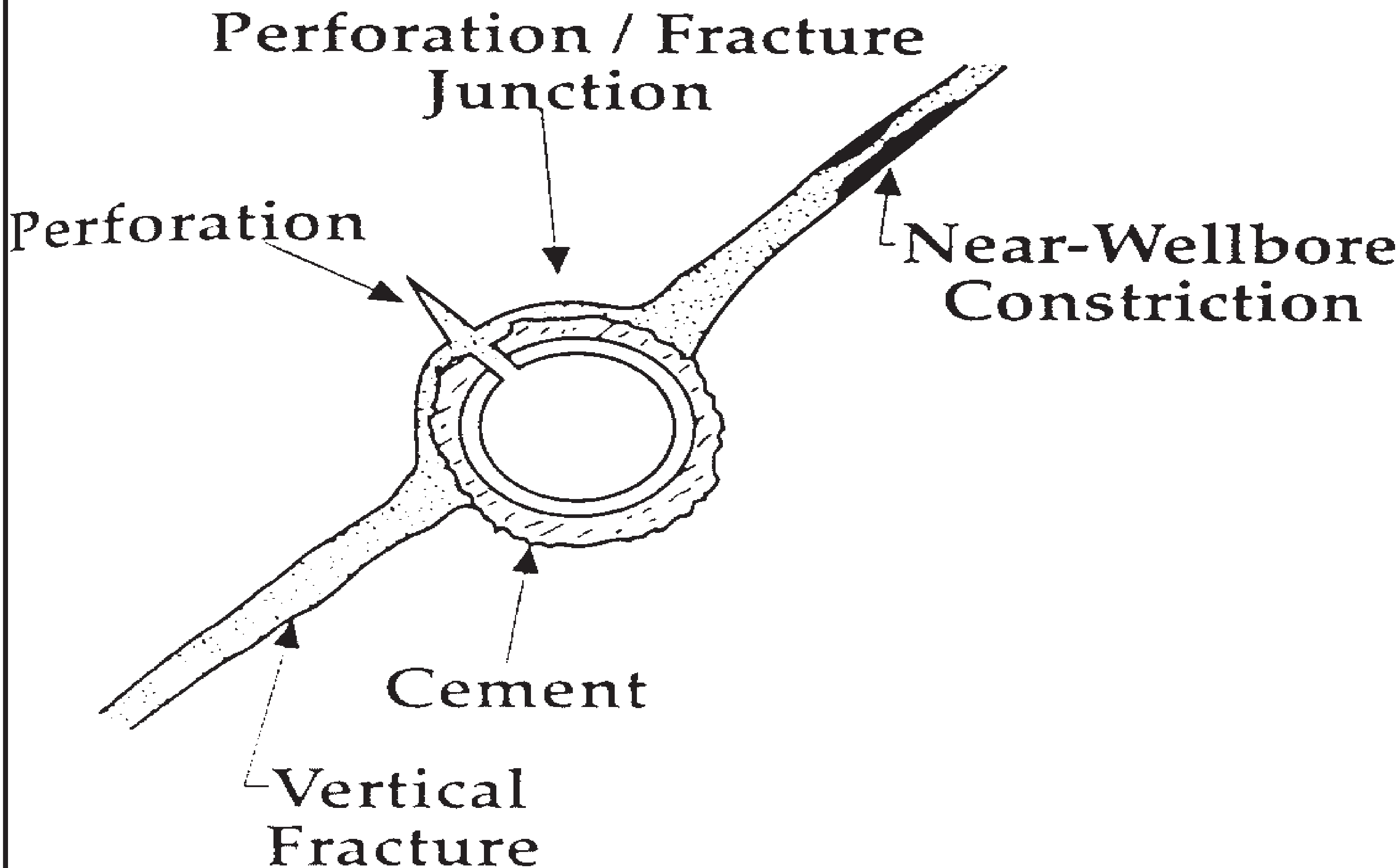
Figure 3-6



Plan View of a Vertical, Two-Winged Coalbed Methane Fracture Showing the Reservoir Region Invaded by Fracturing Fluid Leakoff (Palmer et al., 1991).

7/14/01 kk 1027-3-7.cdr

Figure 3-7



Plan View (Looking Down the Wellbore) of a Vertical Hydraulic Fracture (Palmer et al., 1991)

1027-hf/1027-3-8.eps

Figure 3-8